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April 9, 2004

Docket Clerk
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102-3298

Re: R01-10-024

Dear Docket Clerk:

Enclosed for filing are an original and five (5) copies of Pacific Gas and Electric Company's:

COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY ON "DISCUSSION ON SETTING MARKET PRICE REFERENTS" ISSUED BY COLLABORATIVE STAFF, DATED MARCH 22, 2004

After filing, please return an endorsed stamped copy of it in the enclosed envelope.

Sincerely,

Mark R. Huffman for
Evelyn C. Lee

MRH:pmj

cc: Service List R01-10-024

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development U 39 E	R. 01-10-024

COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY ON "DISCUSSION ON SETTING MARKET PRICE REFERENTS" ISSUED BY COLLABORATIVE STAFF AND DATED MARCH 22, 2004

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COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY ON "DISCUSSION ON SETTING MARKET PRICE REFERENTS" ISSUED BY COLLABORATIVE STAFF AND DATED MARCH 22, 2004

I. INTRODUCTION

PG&E hereby submits its preworkshop comments on the March 22, 2004 "Discussion on Market Price Referents (MPR) – MPR Methodologies To Determine The Long-Term Market Price Of Electricity For Use In California Renewables Portfolio Standard (RPS) Power Solicitations" (MPR Paper) prepared by the California Public Utilities Commission's (Commission) Energy Division, The Division of Strategic Planning, and The California Energy Commission's (CEC) Renewable Energy Program staff (jointly, the Collaborative Staff). The Collaborative Staff have specifically requested parties to comment on and provide prospective values for inputs to be used in a cost model that develops a combined cycle combustion turbine price proxy and a combustion turbine price proxy for baseload and peaking energy, respectively. PG&E welcomes the opportunity to provide input to an interim MPR for renewables procurement. PG&E first addresses some of the overarching policies raised by the MPR Paper, recommends data sources and value ranges for each of the key inputs to the cost model, and offers some procedural recommendations.

II. POLICY CONSIDERATIONS

A. The Renewables Portfolio Standard Provides No Basis For Inferring An IOU Obligation To Pay In Excess Of The MPR For Renewable Energy

One of the basic tenets of the RPS program is that the price paid by an IOU under a long-term contract with an eligible renewable resource will not exceed the market price determined pursuant to the RPS statute.[1] The MPR Paper suggests that the RPS program may be interpreted to allow utilities to propose RPS contracts in which utilities pay more than the MPR for renewable power in order to meet the accelerated goal adopted in the Joint Agency Energy Action Plan given the potential limited supply of Supplemental Energy Payments (SEP).[2]

The major components of the RPS statute cannot be decoupled without creating additional risks and burdens to one or more of the stakeholders. The legislature made the annual obligation to procure renewables contingent upon the availability of funds for SEP payments. Section 399.15 limits an IOU’s annual procurement obligation to the quantity of eligible renewable resources that can be procured with available SEP funds.[3] Even if such above-MPR payments were found to be reasonable, the added expense of a long-term above-market purchase of generation may be burdensome to ratepayers and unfair to the utility. IOUs should not be compelled to pay more than market price for power, particularly where competitive alternatives exist. The Commission should remain mindful of the total ratepayer burden of complying with the original RPS, let alone the accelerated targets.

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[1] Section 399.15(a) (1).

[2] MPR Paper at 7.

[3] Section 399.15(b)(4).

B. Environmental And Externality Benefits Of Renewable Resources Should Not Be Incorporated Into The MPR Because The MPR Is Based Upon The Cost Of Conventional Generation

The MPR Paper cites ORA's recommended addition of "externality mitigation costs" of $0.05 per kWh (ORA testimony page 6).[4] ORA's additional costs cover more than just emissions, they also include water and land impacts.[5] ORA's Appendix A suggests that a broad set of externalities that are not currently quantified, and not currently paid by conventional generators, should be assessed a value for the purpose of inclusion in the MPR. Although the MPR Paper indicates the CPUC has adopted the inclusion of these costs in the MPR in D. 03-06-071, p. 21, the reference is elusive. In any event, "externality mitigation costs" from conventional generation should be included in the capital cost of the proxy unit, so no further adder is necessary.

The MPR Paper also cites Union of Concerned Scientists' (UCS) position on gas hedging. UCS proposes to incorporate environmental mitigation benefits as an additional adder to any gas hedging cost estimate.

PG&E believes the additional costs recommended by ORA and UCS go well beyond the actual offset costs that a typical conventional generator is expected to pay, and well beyond what the Commission intended to be included in the MPR. It appears that ORA and UCS would impute the cost of possible future environmental regulation into the MPR. Consistent with D.03-06-071, only known and actual costs should be included in the MPR. The ORA figures should be analyzed to verify their inclusion only of known and actual costs, consistent with D.03-06-071 at pages 21 ad 22. MPR costs should exclude the effect of potential environmental regulations,

4 *See*, MPR Paper at 17. The "$0.05 per kWh" is a typographical error as the ORA testimony includes a figure of $0.005 per kWh.

5 *Id.*, Appendix A.

as they are "too speculative to include at present."[6]

C. Data From Recent Market Contracts Should Be Used As An Additional Data Point To Evaluate The Reasonableness Of The Proxy MPR

The MPR methodology proposed in the MPR Paper exclusively relies on a proxy plant calculation methodology. PG&E reiterates its belief that the first and best source of information that can be called upon to create the long-term annual price of power are the market prices in "comparable" market-based contracts. The MPR methodology should be revised to accommodate and reflect relevant market contract prices, and bid and ask prices, as described in D.03-06-071 and the RPS statute[7] to establish the MPR.

III. DISCUSSION OF INPUTS

In this section, PG&E addresses all of the inputs identified for party comment by the MPR Paper. First, PG&E discusses principles that are applicable to any generic proxy model – the credibility of data and the need for updates, and the appropriate capital recovery factor. Next, each of the identified inputs is described in terms of both baseload and peaking plants.

A. PRINCIPLES APPLICABLE TO ALL GENERIC PROXY MODELS

1. More Weight Should Be Given To Information Provided By Sources That Are Subject To Fiduciary Responsibility

Capital and operating cost estimates can be gleaned from a variety of sources. However, reliance should rest primarily on sources subject to a fiduciary responsibility, because such sources are required to make a complete and accurate disclosure of relevant information. Such sources include bond financing prospectuses, property tax records, and mandatory filings with

[6] See, D.03-06-071, p. 23. "UCS states that new environmental regulations, such as those regulating carbon dioxide, are likely to result in an increase in gas prices. (*Id*., p. 13.) The methodology we adopt today incorporates known and actual costs. The costs UCS would have us include are too speculative at present. (*See, e.g*., SCE Reply Brief, pp. 7-8; PG&E Reply Brief, p. 37.) We will incorporate them only when they become more definite, both in likelihood and value."

[7] Section 399.15 (c) (1).

regulatory agencies such as the Securities and Exchange Commission.

Other useful sources for cost data include independent engineering reports, consultant studies, items from public records such as court or regulatory hearings and filings, and any other independent analyses. Information from these sources should be given less weight than information arising out of fiduciary responsibility.

The least emphasis or reliance should be placed on information from such sources as press releases, trade press articles, or other such self-published materials because there is no verification or fiduciary responsibility for the project proponent to provide a full and accurate accounting of project costs.

2. Frequency Of Updates And Suggested Methodology Improvements

The MPR Paper explicitly recognizes that the goal of this proceeding is to establish a workable MPR in time for a solicitation this year. Given the need for a timely determination of the MPR methodology and inputs, complete refinement of the model may not be possible in time for this year's solicitations. In addition, participants in this proceeding should benefit from observing the effectiveness of the first solicitation and the resulting MPRs. This experience should enable the Commission to adopt a more stable model for use in the long run.

Thus, PG&E recommends that the methodology developed from this immediate set of workshops be reassessed after the first set of contracts have been approved and any SEP have been determined. A major deficiency in the current methodology is that it ignores differences in the value of power provided by renewable bids relative to that of the proxy plants used to develop the benchmark market prices. Those differences include the value of dispatchability, different energy delivery profiles, forced outages, as well as the reliability of the energy that will be available from the renewable resources. By ignoring these differences, customers are potentially paying for value in the proxy units that the renewable bids do not provide.

In addition to updating the methodology, the Commission should consider an appropriate update frequency for each data source. Each input has its own optimal update frequency, which is roughly related to the volatility of the underlying data, the availability of reliable sources, and the costs involved in retrieving the required data. The Commission should adopt an appropriate update schedule for these inputs, preferably in conjunction with other procurement-related proceedings to better enable the parties to engage in integrated resource planning.

3. Capital Recovery

Capital is a complex input composed of several elements and each deserves discussion. In particular, the capital recovery factor depends on the time period over which the investment is amortized, the discount rate used, and the effect of income tax. As well, the Commission needs to balance the ability to model capital recovery with absolute precision with the desire to have a workable factor.

a. Twenty-Year Depreciation

PG&E recommends the capital recovery factors for both the peaking and baseload MPRs should be based on a recovery period of at least 20 years, regardless of the term of the PPA, and must include allowances for payment of state and federal income taxes. A combined cycle gas turbine (CC) or combustion turbine (CT) typically has an economic life of at least 20 years. Repayment of debt on a shorter time period is not the optimal use of capital. The U.S. Tax Code recognizes that power plants have a long economic life. The federal depreciation method most typically used for combined cycle related assets is the "20-Year 1.5 Declining Balance Methodology". The California state Tax Code for these types of assets uses a 28-year double declining depreciation schedule.

A capacity recovery factor based on a recovery period of less than twenty years ignores the subsequent economic value of the plant. For example, the economic value of the CC at the end of 10 years can be substantial. At the end of the shortened capital recovery time period, the owner of the plant has the opportunity to resell his capacity for a fully "paid off" asset at market prices (or the future MPR that will most likely include another period of full capital recovery).

Wile an owner of an might claim that the project cannot be built due to financing constraints, the Commission must pick the lowest cost producer who can arrange suitable financing. For example, utilities, with adequate regulatory support, can build the plant and repay in 20-30 years. A generator with multiple assets can obtain better financing. Otay Mesa is an example of a project being built under a ten-year contract. As financial markets stabilize, other firms may be able to structure loans to allow refinancing risk.

Shortened economic recovery inflates the capacity payments that ratepayers ultimately pay. If the CPUC insists on burdening the ratepayer with an MPR based on a shorter economic recovery, then the CPUC should allow the utility to have an option to buy project at the end of the ten-year contract period for $1. The owner should not be able to renew a contract extracting a payment for another CC after the plant is completely paid off.

b. Discount Rate Based On 7.5% WACC

PG&E proposes to use 7.5% for the WACC. Assuming that the CT/CC has about the same risk under contract as if it is owned by the utility, this WACC is comprised of 55/45 debt to equity ratio. Debt is assumed to cost about 6.25%, and equity is assumed to have a return on of about 12.13%. The effective tax rate is 40.7%, as discussed below. Any required rate above the 7.5% is would be an unnecessary cost in the MPR of a CC/CT.

c. Allowance For Income Tax

The capital recovery factor (CRF) also must include an allowance for generators to pay income taxes on the income earned. The MPR Paper's straw man calculated the resulting net cash flow needed rather than the revenue payment to allow for payment of taxes. Rather than replicating a cash flow analysis (i.e., solve for revenue payment, given taxes and discount rate), PG&E proposes to adjust the proposed capital recovery factor as follows:

Revenue Requirement CRF = (Original CRF - DEPr * t) / (1-t)

where:

Revenue Requirement CRF = the revised revenue requirement levelized payment

Original CRF = Original Strawman levelized payment (excel function PMT) using the after tax weighted average cost of capital (WACC) as proposed in the MPR Paper divided by capital cost of power plant (as defined in Section B.2).

DEPr = the average ratio of annual depreciation to the original amount (for 20 year 1.5 declining balance, use 0.0515 to reflect acceleration over straight-line for 20 years 1/20)

t = the effective tax rate 40.7% calculated by:

t = FT – ST*FT + ST where:

FT = federal tax rate (35%)
ST = state tax rate (8.84%)

The adjustment to the straw man approximates the payment of state and federal taxes. This adjustment also implicitly adjusts the repayment schedule from the mortgage style in the MS Excel function.

From above, **Revenue Requirement CRF = (Original CRF - DEPr * t) / (1-t).** Then the Revenue Requirement CRF equals 0.1301 where:

Original CRF = PMT (7.5%, 20, capital cost of CC/CT) / (capital cost of CC/CT) = .0981;

DEPr = 0.0515 to reflect the accelerated depreciation;

t = 40.7%.

This calculation gives a reasonable approximation for required annual capacity payments for this workshop even though detailed capital costs and financial structuring of different particular power plants will vary. This calculation uses broad assumptions in areas such as financing (e.g., debt repayment schedule) and depreciation schedules (i.e., certain assets on plants have different schedules, land is not depreciable, write-off at end of economic life).

B. Non-Fuel Costs – Baseload And Peaking Proxies

1. Plant Capacity

For the purposes of developing CC values, PG&E recommends that data should reflect a generic plant such as a 2x1 GE Frame 7FA CC project, that includes wet cooling, evaporative inlet air chillers, duct burners, and SCR and CO catalyst to control emissions. The plant output should be calculated at ISO conditions and not include duct firing.

For the CT proxy peaking project, the CEC is using a single unit advanced technology CT such as the GE 7E or 7F including SCR for emission control. Other sources of information on potential proxy peaking projects are EPRI and EIA data. Both EPRI, in their 2001 Technical Assessment Guide, and EIA, in their Assumption to the Annual Energy Outlook 2002, identify conventional combustion turbine technology projects. Again, PG&E recommends the plant output be derived at ISO conditions.

2. Capital Costs

Capital costs should include all one-time upfront costs necessary to develop, permit, design, finance, and construct the project. These costs include:

- Plant engineering, procurement and construction costs (EPC), including the acquisition cost of the power island;
- Balance of plant costs (BOP) including water treatment, plant buildings, chemical/water storage etc.;
- Water interconnection;
- Gas interconnection;
- Transmission interconnection (including plant switchyard and “gen-tie” costs);
- Plant site and all easements and rights-of-way;
- Development and permitting costs (including land use mitigation);
- Emission Reduction Credits (ERCs);
- Capital spares;

- Start-up and mobilization costs;
- Local benefits and mitigation costs (nuisance abatement)
- General and administrative;
- Contingency and working capital;
- Insurance and taxes during construction; and
- all financing transaction costs (IDC, fees, lender closing costs, etc.)

Debt service interest and any investment returns are captured in the capital recovery factor discussed above.

a. **Generating Facility**

Total capital costs for a new combined cycle project are estimated to be in the $650 per kW to $700 per kW range. This estimate is based primarily on the information contained in Southern California Edison Company Section 205 filing to FERC on December 19, 2003.[8] This filing references multiple sources to develop a cost basis for a baseload CC project located in California.[9] In addition, PG&E is in the process of collecting and reviewing stock and bond offerings of major power industry companies to obtain capital and operating cost data. PG&E hopes to be able to reference this information during the April 15th MPR workshop.

If the CEC proxy is used, PG&E proposes an adjusted CEC estimate of $497 per kW be used as the total capital costs. The CEC in its August 2003 paper used an in-service cost of $475 per kW, which according to the CEC, does not include an estimate for direct assignment transmission facilities costs. Therefore, PG&E suggests that an additional $22 per kW be added to the CEC's CT capital cost estimate to cover these costs. The derivation of the direct assignment facility unit cost is explained below.

Another source for the capital costs of a CT is EPRI. In EPRI's 2001 Technical

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8 (Docket No. ER04-316-000) SCE requests approval of the Power Purchase Agreement (PPA) between SCE and Mountainview Power Company, LLC (MVL).

9 These sources include, among others: 1) the proposed PPA between SCE and MVL, 2) an Affidavit of Joseph B. Wharton, and 3) a Stone & Webster capital cost analysis.

Assessment Guide, the total capital cost of a conventional technology combustion turbine is $380 per kW, in 2001 dollars.

b. Direct-Assignment Transmission Facilities ("Gen-Tie")

The MPR Paper requests estimates for direct assignment transmission facilities (often called "gen-ties"). The capital cost estimates above and most publicly available data sources typically group these costs into the overall project capital cost. For the purpose of discussion, PG&E has calculated these costs consistent with recent comparable cost estimates. While there is no such thing as a "standard" or "generic" interconnection to the high voltage transmission system, PG&E does have the recent experience of conducting system impact studies and facility studies for multiple CC and CT power projects in its service territory, and has drawn upon this experience to derive a standard gen-tie cost estimate.

The direct assignment transmission facility costs necessary to interconnect both a baseload and peaking project to the high voltage transmission system are divided into two main components. First, a large baseload CC project is assumed to have a two-mile, 230kV radial transmission line interconnection estimated to cost $1.1 million, which converts to approximately $550 thousand per mile or $2.25 per kW. Second, after devising a "generic" substation interconnection scheme, PG&E recommends assuming a $2.3 million cost ($4.60 per kW) for the costs of the radial line termination into the substation and associated network upgrades.

Similarly, for a CT project, a two-mile, 115 kV radial transmission line interconnection is assumed and estimated to cost $900 thousand, which converts to approximately $450 thousand per mile or $9.00 per kW. The "generic" substation and network interconnection costs for the CT project are estimated to be $1.3 million or $13 per kW.

The MPR Paper also requests parties to provide specific estimates for "Local Land and

Permit Costs" on a dollars per kW basis. Such costs are included in the capital cost estimates above and thus, PG&E does not offer any separately stated cost assumptions for this capital cost component.

3. Capacity Factor

a. Baseload Proxy

For the purposes of a baseload RPS MPR, the correct capacity factor to assume is the maximum operational capacity (i.e., always-on except for scheduled maintenance), which the CEC reported at 92%. The high capacity factor is appropriate because the RPS baseload contract is a fixed price contract for delivery around the clock, subject to the RPS unit availability. The fact that many merchant combined-cycle plants in the market actually operate at lower levels should not affect this value. The baseload contract in RPS is a fixed price contract for 24X7 delivery. The most typical reasons why an operator might make an economic decision to operate at lower than maximum operational capacity do not suggest that a lower capacity should be used to calculate the MPR.

The baseload MPR proxy is based on the revenue stream that a combined cycle owner needs to fulfill a contract for a total year of delivery. The generator still recovers at least the original margin in low-price hours when it might substitute market power for generated power.

Under some fixed-price baseload contracts, operators that have the option to deliver system energy instead of unit-contingent energy would curtail production when the market price is below their short-term variable costs (primarily fuel price times heat rate plus variable O&M) and fulfill their contract by buying and delivering market-price energy. If a CC plant under a fixed price contract actually operates at less than full operating capacity, due to these conditions, that is because the plant owner has chosen to curtail to buy system power below the plant owner's variable costs of generating power.

However, the plant owner is still selling the power at the contracted fixed price. Therefore, the plant owner is earning at least as much contribution toward the CC's fixed costs as it would if were to run its own plant. If one were to artificially raise the MPR by assuming that the plant ower was not earning any contribution toward the CC's fixed costs under such circumstances, then one would simply be building an over-recovery of these costs into the MPR. Therefore, the MPR should be set assuming that the facility runs at maximum operational capacity.

b. **Peaking Proxy**

For purposes of the Peaking Proxy, the capacity factor should reflect the operation of the CEC 9,500 Btu per kWh heat rate proxy unit. Using today's current and forward prices, a 9,500 Btu per kWh heat rate unit would correspond to a capacity factor range of 30% to 50%, depending on the unit's variable costs (which depend on the cost of fuel, and variable O&M costs). The 10% capacity factor in the MPR Paper is far below the operational range expected for a new combustion turbine with a 9,500 Btu per kWh heat rate.

The peaking proxy market referent price should only apply to the evaluation of renewable resources with comparable operating characteristics that match the derivation of the peaking market referent price. Specifically, there should be a high degree of certainty that the renewable resource will be available during the peak hours of every month; that it should be callable with quick start capability, and be able to ramp up and down to meet utility load. These peaking resources should be available throughout the year to meet 30% to 50% of the highest demand hours each year. A peaking renewable resource should also be able to provide ancillary services and replacement reserves for the utility. If the renewable resources do not have operating characteristics or capabilities consistent with a peaking proxy, then such resources should be evaluated using the baseload proxy, adjusted for their particular availability.

4. **Fixed O&M Costs**

Fixed O&M costs include all annual reoccurring fixed costs that are independent of hours of operation. The main elements of this category are labor and overhead, annual inspections, maintenance and part replacement programs, property taxes, permit fees, utilities, and insurance.

PG&E estimates the fixed O&M costs of the baseload CC project to range from $15-$25 per kW in the first year of operation. These costs then need to be transformed into levelized numbers for use with the 10, 15 and 20 year MPRs. The 20-year baseload MPR translates into a range of $17-29 per kW. For the peaking market price referent, the CEC has estimated a value of $22 per kW for the levelized fixed O&M of a CT.

5. **Variable O&M Costs**

Variable O&M costs include all annual recurring costs that are dependent upon the actual or forecasted run hours of the power plant. The principal variable O&M components include parts and service, consumables, water, water treatment and disposal, major maintenance and overhauls (annualized based on the capacity factor), and output-based emissions taxes. Over a short time horizon, some of these costs do not strictly vary based on output. Nonetheless, it is sufficiently accurate to state these costs on a dollar per kWh basis.

PG&E estimates the variable O&M costs for a baseload CC range from $0.0020 - 0.0030 per kWh in the first year of operation. These costs need to be transformed into levelized numbers for use with the 10, 15 and 20 year MPRs. For the 20 year baseload MPR, this levelized range is $0.0023 - $0.0035 per kWh. For the peaking MPR, the CEC has estimated a value of $0.0152 per kWh for the variable O&M costs of a CT. The CPUC MPR Paper has suggested a value of $0.006 per kWh. Combining the two estimates for the 20 year MPR produces a levelized range of $0.006 - 0.0171 per kWh.

6. Heat Rate

Heat rate is a significant driver of a plant's variable costs. Heat rates of modern plants are significantly lower than those of a generation ago, and innovation might bring further efficiency improvements. At the same time, a plant's heat rate degrades over time. PG&E recommends assuming a heat rate degradation factor of 2% from new and clean performance levels. This is based on standard industry practice and project financing convention. PG&E considers degraded heat rates in the range of 7,000 – 7,100 Btu per kWh representative for a baseload CC.

For a peaking CT, PG&E suggests that the CEC CT heat rate of 9,300 Btu per kWh also be modified by a 2% heat rate degradation factor. This will increase the CEC's heat rate for a CT to 9,500 Btu per kWh.

C. Fuel Assumptions

1. Commodity Price For Fuel

a. Use New York Mercantile Exchange Gas Price For First Five Years Of MPR

The MPR must, as defined by SB 1078, include fixed-price fuel costs associated with fixed price electricity from new generating facilities.[10] As outlined in the MPR Paper, since the MPR will include proxies for 10, 15 and 20-year fixed electric prices, the Collaborative Staff will need 10, 15, and 20-year fixed gas prices. Such gas must be priced as delivered to the burner tip in California. Long-term, fixed-price natural gas contracts of this length trade infrequently in the market today. Thus, the Commission must use an alternative method of deriving a long-term, fixed-price for gas.

The most reliable source of forward gas prices is the New York Mercantile Exchange

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[10] Section 399.15(C)(2).

(NYMEX) futures contract. NYMEX closing prices are readily available on the exchanges' website.[11] It is a robust and liquid market and maintains strict rules and regulations under the watch of the Commodity and Futures Trade Commission (CFTC). The NYMEX is far more transparent and liquid than either the physical gas market or the Over-the-Counter (OTC) financial gas market.

The NYMEX offers 72 consecutive forward monthly gas futures contracts. The NYMEX publishes closing prices for all 72 contracts on a daily basis. For purposes of calculating MPR fuel costs, one should group the NYMEX contracts into calendar years and calculate a simple average for each year. For example, using the NYMEX closing prices for April 9, 2004, one could calculate the calendar-year forward prices for 2005 through 2009 (NYMEX prices for 2010 are only available through April of 2010). Based on this method, PG&E recommends that the Commission use NYMEX futures pricing exclusively for the initial years of MPR calculations.

b. Use Fundamentals Forecasts To Extend Gas Price Forecast Through Year 20 Of The MPR

Since, for the purposes of calculating the MPR, the NYMEX is limited to at most six years for gas price discovery and since the physical and OTC gas markets are not liquid or transparent beyond 18-months, the Commission can turn to gas price forecasts based on fundamentals to predict gas prices beyond the calendar years available from NYMEX. This is the only practical and transparent method of pricing gas for the complete terms of 10, 15 and 20 years.

That said, however, PG&E must emphasize to the Commission that the sources of such

[11] http://www.nymex.com/jsp/markets/ng_pre_agree.jsp

forecasts must be from independent, nationally-respected firms and agencies.[12] These forecasts must be available either publicly or on a subscription basis. These forecasts must also be location-specific so that they may be adjusted to reflect burner-tip costs in California. PG&E recommends using a minimum of three sources for these forecasts to reduce the influence of systematic bias by one source.

The MPR Paper asks for comments on how baseload and peaking gas costs would differ based on time of year of consumption or whether annual average is OK. In general, gas prices are lower than the annual average during the summer period when peaking units are most often dispatched. PG&E used the five available calendar year NYMEX forward curve discussed above and found that mid-summer gas prices (June through September) average 95.8% of annual average prices on a nominal basis. PG&E proposes using this adjustment for the peaking MPR fuel cost.

The NYMEX forward curve and the fundamentals forecasts should be blended as follows:

- ✓ Calculate annual averages with the NYMEX data for the available calendar years of operation of the baseload facility (years one through the initial years of the MPR forward curve).
- ✓ The fundamentals forecasts can be combined with a simple average calculation for each calendar year after those available from NYMEX. Forecasts in five-year intervals (i.e., 2011 to 2015) should be split into five one-year prices for this step.
- ✓ Combine the NYMEX and fundamentals portions of the forward curve into a single 20-year MPR gas forward curve (one price for each calendar year, 20

[12] In this context independent means that the source is not a party to the RPS proceeding.

prices).

- ✓ Calculate the MPR 10, 15 and 20-year forecasts by calculating levelized values from the 20-year MPR gas forward curve.

PG&E recommends that the Commission update forward gas prices prior to each solicitation. NYMEX gas prices should be update using information from the NYMEX website. Fundamentals forecasts should be updated to reflect the most recent forecasts available from CERA, PIRA, and EIA.

c. **Basis/Transportation Differentials**

The Staff's MPR Paper correctly points out that the MPR must take into account locational differences in gas prices. Forward or forecasted gas prices discussed above must be adjusted to reflect a burner-tip price, to the extent that they do not represent such a price.

For NYMEX forward prices, Staff must estimate a basis adjustment from the Henry Hub in Louisiana to either the Southern California for SCE and SDG&E or to the PG&E Citygate for PG&E. Basis must be used because there is no direct gas transportation route from Henry Hub to California. Fortunately, the NYMEX added a trade clearing service for OTC basis swaps in May of 2002, and publishes monthly basis prices at the end of each trading day. As of January 2004, NYMEX had cleared more than one million swap contracts through this service. PG&E recommends using this data to adjust the NYMEX forward prices discussed above to reflect California market prices.

For prices that are forecasted based on fundamentals, Staff should use location-adjusted forecasts wherever they are available. For example, both PIRA and CERA offer long-term forecasts of California gas prices (PIRA forecasts California prices directly whereas CERA forecasts Henry Hub prices and California basis).

The EIA forecast represents a Citygate gas price specific to electric generation. EIA states that electric generators "receive most of their natural gas directly from interstate pipelines, avoiding local distribution charges." Thus it does not include distribution charges in its forecast. Since this is not the case in California, the EIA forecast must be adjusted for local distribution charges for the MPR.[13]

For fundamentals forecasts that are not specific to California, Staff must make an adjustment for transportation to California (again, for the Southern California for SCE and SDG&E or to the PG&E Citygate for PG&E). The best method for this adjustment is to use current firm transportation tariffs from interstate pipelines to calculate the cost to move gas from the forecasted location to the appropriate market point in California.[14] Such calculations must assume that the generator's pipeline capacity is used at a 92% capacity factor to be consistent with the MPR generation capacity factor assumption. The Producer Price Index for natural gas transportation for future years should escalate these pipeline tariffs.

The MPR Paper invites comments on whether interruptible and storage should be considered in the fuel cost calculations. Interruptible pipeline capacity is inappropriate for firm, baseload generation because it is not reliable enough to supply firm generation commitments. Staff should use interruptible or as-available gas transportation tariffs, however, to estimate locational differences for as-available generation capacity. This is common practice in the industry because interruptible pipeline rates are 100% volumetric whereas firm interstate pipeline rates are comprised of 99% fixed demand charges (e.g. the capacity is a fixed monthly cost for 99% of the tariff rate). Firm pipeline capacity is far too expensive for an intermittent gas

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13 EIA Annual Energy Outlook 2004 with Projections to 2025, http://www.eia.doe.gov/oiaf/aeo/gas.html#ngsc.

14 This method applies to firm generation capacity only. Staff should use interruptible or as-available gas transportation tariffs to estimate locational differences for as-available generation capacity. This is common practice in the industry because firm interstate pipeline rates are comprised on 99% fixed demand charges (e.g. the capacity is a fixed monthly cost for 99% of the tariff rate).

consumer such as a peaking facility.

Gas storage is not needed to supply either baseload generation or peaking. Firm contracts for gas supply and gas transportation are adequate to supply fuel for baseload generation. Spot trading and interruptible gas transportation are adequate for peaking generation. Storage is not cost effective for either need. For example, PG&E issued an RFO for gas storage on behalf of DWR (for PG&E's allocated DWR contracts that include baseload and peaking resources) in February, 2004. The best offer from three storage providers yielded a cost benefit ratio of 0.63.

Fuel prices at the above-referenced market points should be adjusted for local transmission and distribution rates. Such rates should be applied in the same manner as interstate pipeline rates.

- ✓ Source: NYMEX Web site, CERA, PIRA, EIA, Pipelines' Web sites
- ✓ Frequency of Update: Basis must be updated for each solicitation, all other data quarterly (especially pipeline in-kind shrinkage rates)

d. **PG&E Estimate of Gas Fuel Costs**

Using the methodologies described above, PG&E calculated the following gas fuel costs:

Baseload Gas Fuel Cost ($/MMBtu) Term		
10-year	15-year	20-year
$5.07	$5.08	$5.12

Peaker Gas Fuel Cost ($/MMBtu) Term		
10-year	15-year	20-year
$4.86	$4.87	$4.90

2. **Cost of Hedging**

In the past, electric generators fixed natural gas prices by either entering into long-term, fixed-price supply contracts or by executing long-term fixed-for-floating swaps.[15] These were the cleanest and most cost-effective long-term hedges in support of long-term, fixed-priced electricity contracts. In a liquid market, the cost of such a hedge is one-half the bid/ask spread for the specific contract.

The energy crisis of 2000 - 2001 and the following credit crunch has caused such long-term products to disappear from the market. Fixed-for-floating swaps of 10, 15 or 20 year terms are quoted by large banks (who have entered the energy derivatives market in recent years) but they are not liquid. Since the long-term cost of hedging cannot be observed in the market, Staff must use another method to estimate such a cost for firm capacity. Hedging cost is not necessary for as-available generation capacity since a generator would not hedge such a contract.

Since long-term hedging tools are not readily available in the market, generators use a "stack-and-roll" technique to achieve the benefits of a fixed-price hedge using shorter-term products. The technique begins with locking a forward gas price for approximately two years using fixed-for-floating swaps (or futures and basis contracts). Moving forward in time, the generator locks in the price of an additional seasonal strip of gas prices as the current season comes to a close. This maintains a roughly two-year, rolling fixed gas price.

The cost of the "stack-and-roll" technique is one-half the bid/ask spread of the seasonal strips that the generator purchases and the financing cost of the collateral necessary to maintain such a position. For simplicity, PG&E uses NYMEX and basis contracts to estimate such a cost.

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15 Such transactions were backed by long-term, firm gas transportation contracts to the facility. Fixed-for-floating swaps are traded for a market point nearest the generating facility.

The bid/ask spreads of NYMEX futures contracts are readily observable on the floor of the exchange[16]. PG&E assumes that basis contracts have the same bid/ask spread as their underlying NYMEX contracts.[17] PG&E estimated the cost of this strategy with the following results:

	Cost ($/MMBtu)
Bid/Ask Spread	$0.071
Collateral Carrying Cost	$0.065
Total Hedging Cost	$0.136

The Commission Staff's MPR Paper contemplates whether, according to an Lawrence Berkeley National Lab Study, "forward prices for natural gas may have exceeded some published gas price forecasts" and whether "forecasted prices should be adjusted upwards to account for this recent empirical difference between forecasts and forwards".[18]

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[16] PG&E, working with its NYMEX broker, collected representative bid/ask spreads from the NYMEX trading floor. The results were used in support of this analysis.

[17] This assumption will slightly overstate this cost.

[18] Energy Division MPR Paper, p 19.

There is insufficient factual or theoretical basis for adjusting forecasted prices upward to account for any perceived empirical difference between forecasts and forwards. Early versions of the LBL study relied on a troublingly small price sample size from trading in 2000 and 2001: the height of the energy crisis.[19] Also, this early study relied on data from Enron Online which was cited by FERC staff as one of the primary vehicles used for gas market manipulation. Since June 2002, LBNL has updated their study twice, the most recent being January 2004. In the conclusion section of the updated study, the authors still caveat that "cannot easily extrapolate these findings beyond the time period of [their] data (2000-2003), or to contract terms longer than those examined (i.e., > 10 years), . . . ".[20] As well, when considering the possible theoretical explanations for the observed empirical premiums in the forward versus forecast prices, the authors "found each of them to be neither fully satisfying nor easily refutable."[21]

D. Summary Of Inputs For Baseload And Peaking MPR Inputs

PG&E presents a summary of its recommended MPR inputs in the Tables below.

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[19] Quantifying the Value that Wind Power Provides as a Hedge Against Volatile Natural Gas Prices Bolinger, M., R. Wiser and W. Golove June 2002 LBNL-50484

[20] Bolinger, M., R. Wiser, and W. Golove , Accounting for Fuel Price Risk When Comparing Renewable to Gas-Fired Generation: The Role of Forward Natural Gas Prices , January 2004, LBNL-54751.

[21] The three categories of explanations the authors offer are that 1) Hedging is not costless (due to net hedging pressure, systematic risk in natural gas prices, and transactions costs), 2) The forecasts are out of tune with the market, and 3) Other data issues drive the premium.

PACIFIC GAS AND ELECTRIC
TABLE D-1
BASELOAD PROXY INPUTS

	Baseload Proxy Plant Characteristics	PG&E 10 Year MPR	PG&E 15 Year MPR	PG&E 20 Year MPR	Comments
(1)	Plant Capacity (MW)	500	500	500	
(2)	Capital Cost ($/kW)	650-700	650-700	650-700	Includes gen-tie costs
(3)	Capital Recovery Factor (Calculated)	0.1301	0.1301	0.1301	7.5 % WACC and 20 year capital recovery
(4)	Capacity Factor	92%	92%	92%	
(5)	Fixed O&M Costs ($/kW/yr)	16-27	17-28	17-29	Levelized based on first year costs $15- 25/kW-yr
(6)	Gas Fuel Costs ($/MMBtu)	5.07	5.08	5.12	based on NYMEX and average of PIRA, EIA and CERA forecasts
(6a)	Hedging Costs ($/MMBtu)	0.136	0.136	0.136	PG&E derived
(7)	Heat Rate (Btu/kWh)	7,000-7,100	7,000-7,100	7,000-7,100	Includes 2% degradation
(13)	Variable O&M Costs ($/kWh)	0.0022-0.0032	0.0022-0.0034	0.0023-0.0035	Levelized based on first year costs $0.002-0.003/kWh

PACIFIC GAS AND ELECTRIC
TABLE D-2
COMBUSTION TURBINE PROXY INPUTS

	Combustion Turbine Proxy Plant Characteristics	**PG&E 10 Year MPR**	**PG&E 15 Year MPR**	**PG&E 20 Year MPR**	**Comments**
(1)	Plant Capacity (MW)	100	100	100	
(2)	Capital Cost ($/kW)	$497	$497	$497	CEC Report, Appendix D, Table D-10 Capital Cost + $22 gen tie cost
(3)	Capital Recovery Factor (Calculated)	0.1301	0.1301	0.1301	7.5 % WACC and 20 year capital recovery
(4)	Capacity Factor	30-50%	30-50%	30-50%	
(5)	Fixed O&M Costs ($/kW/yr)	22	22	22	CEC Report, Appendix D, Table D-10 Levelized
(6)	Gas Fuel Costs ($/MMBtu)	4.86	4.87	4.90	based on NYMEX and average of PIRA, EIA and CERA and modified to summer pricing
(6a)	Hedging Costs ($/MMBtu)	n.a.	n.a.	n.a.	
(7)	Heat Rate (Btu/kWh)	9,500	9,500	9,500	CEC Report, Appendix D, Table D-10 with 2% degradation
(13)	Variable O&M Costs ($/kWh)	0.006-0.0183	0.006-0.0177	0.006-0.0171	range between CPUC placeholder and CEC Report, Appendix D Table D-9 levelized

E. Comments On Proposed Process For Calculating And Disclosing Mprs

The MPR Paper includes a process for discussion. The process seems to assume that the only input required to calculate the MPR would be long-term fuel price assessments; the other cost components will be in place. This process appears to be satisfactory for the 2004 solicitation

The staff explicitly requested comment on the proposal to protect from disclosure its formula for developing the gas price component of the MPR.

Although the stagnant economy seems to have rendered the non-fuel components fairly constant, during subsequent years, PG&E believes that it may be prudent for the Commission to solicit inputs for all economic factors at the same time as the fuel forecast.

F. Procedural Recommendations / Next Steps

1. One Workshop Or Two

PG&E recommends that a second workshop be held on the reserved date of April 20. The additional workshop time will enable the Commission and the parties to request follow up data, to verify data, to perform calculations, and facilitate analysis and dialogue that may help to eliminate immaterial issues from the decision making process.

2. Workshop Report And Opportunity For Comments

Typically, the Commission staff issues a workshop report following a workshop such as this one, and parties may comment on the report. This seems to be a fruitful way of ensuring the accuracy of the record so the Commission's decision will be based on facts. PG&E recommends that this practice be observed with respect to the MPR workshop. Even though the inputs will obviously not be fixed, and the Commission cannot indicate which inputs it intends to use to create the MPR, we believe that the opportunity to comment on a workshop report will greatly assist the Commission.

Respectfully Submitted,

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Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

April 9, 2004

CERTIFICATE OF SERVICE BY ELECTRONIC MAIL AND U.S. MAIL

I, the undersigned, state that I am a citizen of the United States and am employed in the City and County of San Francisco; that I am over the age of eighteen (18) years and not a party to the within cause; and that my business address is Pacific Gas and Electric Company, Law Department B30A, 77 Beale Street, San Francisco, CA 94105.

I am readily familiar with the business practice of Pacific Gas and Electric Company for collection and processing of correspondence for mailing with the United States Postal Service. In the ordinary course of business, correspondence is deposited with the United States Postal Service the same day it is submitted for mailing.

On the 9th day of April 2004, I served a true copy of:

COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY ON "DISCUSSION ON SETTING MARKET PRICE REFERENTS" ISSUED BY COLLABORATIVE STAFF, DATED MARCH 22, 2004

[XX] By Electronic Mail – serving the enclosed via e-mail transmission to each of the parties listed on the official service list for R. 01-10-024 with an e-mail address.

[XX] By U.S. Mail – by placing the enclosed for collection and mailing, in the course of ordinary business practice, with other correspondence of Pacific Gas and Electric Company, enclosed in a sealed envelope, with postage fully prepaid, addressed to those parties listed on the official service list for R. 01-10-024.

I certify and declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on this 9th day of April 2004 at San Francisco, California.

PATRICIA M. JORDAN